PETROMET RESOURCES LIMITED

1997

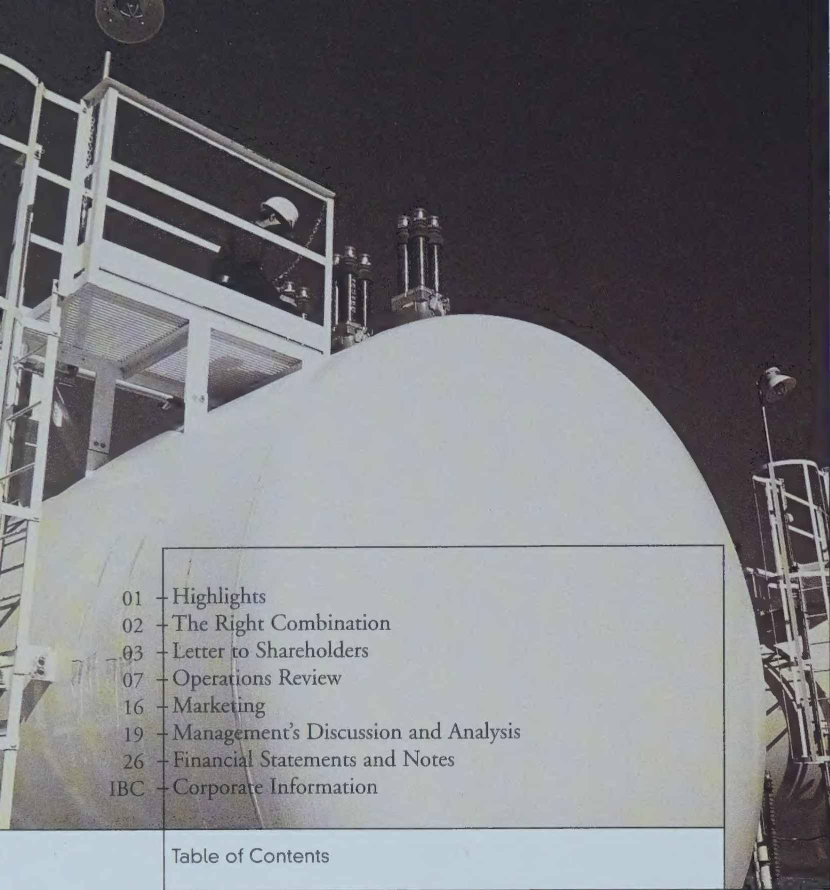


Table of Contents

Profile Petromet Resources Limited is an exploration, development and production company focused primarily on natural gas. The Company has a strong operational base in west central Alberta including large undeveloped land holdings, extensive infrastructure and processing facilities. An emphasis on growth through exploration and development has resulted in Petromet's average daily production reaching 4,700 barrels of oil equivalent in 1997.

Petromet's common shares and convertible debentures trade on The Toronto Stock Exchange under the symbols "PNT" and "PNT.DB", respectively, and its common shares trade on NASDAQ under the symbol "PNTGF".

The cover of the 1997 Annual Report reflects how Petromet has achieved success through the right combination of two essential factors – the expertise of its staff and a commitment to internally generated growth through exploration and development. The cover design was inspired by Douglas Andrews, Senior Geologist with Petromet.

HIGHLIGHTS

	1997	1996	% Change
Financial ($ millions, except per share)			
Gross revenue	33.9	27.9	22
Net income from operations	4.4	3.6	22
Net income	4.4	6.1	(28)
Per share	0.11	0.18	(39)
Cash flow	20.6	15.9	30
Per share	0.53	0.46	15
Capital expenditures	49.6	23.2	114
Long-term debt, net of working capital	46.1	37.5	23
Shareholders' equity	97.9	80.1	22
Total assets	163.2	129.4	26
Common shares outstanding (millions)			
Basic	42.7	37.0	15
Weighted average	38.5	34.3	12
Operating			
Production			
Natural gas (mmcf/d)	37.2	33.1	12
Oil & NGL (bbls/d)	971	859	13
BOE/d	4,691	4,169	13
Average prices			
Natural gas ($/mcf)	1.85	1.63	13
Oil & NGL ($/bbl)	23.42	24.25	(3)
BOE ($)	19.82	18.30	8
Operating expenses ($/BOE)	2.07	2.09	(1)
General and administrative ($/BOE)	0.66	0.90	(27)
Reserves – proven plus probable			
Natural gas (bcf)	232.1	207.2	12
Oil & NGL (mbbls)	6,527	4,559	43
Total (mboe)	29,737	25,279	18
Undeveloped land (thousands of acres)			
Gross	575	457	26
Net	520	414	26
Average working interest (%)	90	91	
Drilling activity			
Gross	31	29	7
Net	25	21	19
Success rate (%)	64	62	

THE RIGHT COMBINATION

In 1997 Petromet achieved growth in production, reserves and revenue. We believe this growth is directly attributable to the right combination of qualified people supporting our exploration, development and production initiatives.

Our operations follow a fundamental set of corporate strategies that have guided Petromet's growth. We will continue to apply these strategies in 1998 and beyond.

Corporate Strategies

- Capture upstream exploration and development opportunities afforded by the Company's excellent gas processing infrastructure;
- Focus on multi-zone potential of natural gas-prone areas in west central Alberta;
- Capitalize on the Company's extensive undeveloped land position;
- Utilize leading edge technology and technical expertise to enhance success;
- Maintain an exposure to high risk/high reward exploration while increasing the emphasis on exploitation and complementary acquisitions;
- Preserve and enhance the Company's superior operating efficiency; and
- Create shareholder value through the disciplined assessment of full cycle project economics.

1998 Objectives

- Continue exploration and development in established production areas of Bigstone and Wild River;
- Follow-up exploration and development in new growth areas of Kakwa and High Prairie;
- Further deep drilling at Wild River on additional Leduc reef anomalies defined by 3-D seismic;
- Maximize the value of our existing assets including a large undeveloped land position and strategically located production facilities; and
- Focus additional technical expertise and capital spending on complementary acquisitions.

LETTER TO SHAREHOLDERS

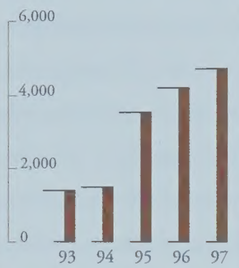
Nineteen ninety-seven was a year of steady progress for Petromet. Thirty-one wells were drilled leading to the highest levels of production and reserves in the Company's history. We also ensured the opportunity for future increases by establishing two new growth areas for the Company – Kakwa and High Prairie – which will generate increased production and revenue.

The achievements of 1997 are largely due to the implementation of Petromet's corporate strategies. The strategies reflect what we do best – grow the Company's asset base primarily through natural gas exploration and development on extensive undeveloped lands in west central Alberta.

While these strategies are important, the people who implement them are most responsible for our success. We are proud of the contributions made by all staff members who bring unique perspectives to various areas of expertise.

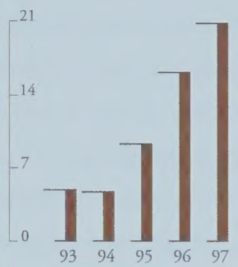
Overview of 1997 The year was characterized by an active and highly competitive Canadian oil and gas industry. On the natural gas side, a positive influence on our performance was strong commodity prices throughout the year. The average gas price received by Petromet in 1997 was $1.85 per thousand cubic feet, 13 percent above the 1996 realized price. Challenges we faced included higher industry costs, difficulties in procuring equipment and services due to increased industry competition, and limited access in some regions. Within this environment, Petromet's approach was to emphasize planning and operational efficiency, thereby enabling us to carry out our capital program.

Financial highlights of the year included cash flow from operations which increased 30 percent to a record $20.6 million from $15.9 million in 1996. Net income from operations increased 22 percent to $4.4 million from $3.6 million in the previous year.



PRODUCTION

BOE/D



CASH FLOW

$ MILLIONS

Integral to our corporate strategy is continued attention to cost control, ownership of facilities and efficiency of our operations. In 1997, these contributed to reduced general and administrative expenses of $0.66 per barrel of oil equivalent. Operating costs were also maintained at a low level of $2.07 per barrel of oil equivalent. Our capital expenditure program of $50 million was more than double that of the 1996 program, resulting from increased exploration, higher industry costs, increased facilities and land expenditures and several minor acquisitions.

During the third quarter, in order to fund exploration and development programs, we issued 2.7 million flow-through common shares at $4.05 per share and 2.9 million common shares at $3.75 per share for gross proceeds of $22 million.

Operationally, Petromet's daily production in 1997 increased 13 percent to 4,690 barrels of oil equivalent compared to 4,170 barrels of oil equivalent in 1996. While this increase was less than our growth target set at the beginning of the year, significant discoveries in late 1997 are expected to result in stronger growth in the first half of 1998.

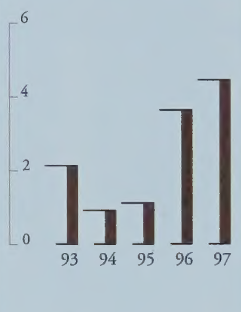
Our extensive land holdings provide the foundation for reserves and production growth. Petromet's undeveloped acreage increased to 520,000 net acres in 1997 compared to 414,000 net acres in 1996. We achieved growth in our natural gas reserves during 1997 to 232 billion cubic feet, a 12 percent increase above the 207 billion cubic feet in 1996. Crude oil and natural gas liquids reserves increased to 6.5 million barrels from 4.6 million barrels in the previous year due to successful oil discoveries in a new core area. Petromet's proven reserve life index of approximately 12 years reflects the quality of reservoir and associated long life reserves we target.

Bigstone remains Petromet's most important producing asset, including a large focused land position and an extensive infrastructure of roads, gathering systems, compression and plant facilities. The Company's ongoing strategy focuses on the exploitation of existing pools with conventional vertical and underbalanced horizontal wells.

At Wild River, our other established gas area, Petromet began to target deeper horizons in 1997. A 4,200 metre Leduc reef test resulted in a sweet natural gas discovery, which came on-stream in March 1998.

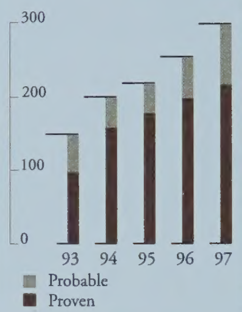
Kakwa was one of two new growth areas established by Petromet in 1997. This gas prone region, at which production commenced in December 1997, contains multi-zone reservoirs to depths of 3,000 metres. The other new area is High Prairie, the Company's first light oil project which began production in the last quarter of 1997.

Petromet's strategies were founded upon the fundamental belief that natural gas will be the long-term commodity of choice in North America. Historically, Petromet's production mix has been approximately 80 percent natural gas and 20 percent oil and natural gas liquids.



NET INCOME FROM OPERATIONS

$ MILLIONS



RESERVES

BCFE

While our focus on natural gas has not always proven beneficial, particularly during warm winters and periods of restricted markets due to the lack of pipeline capacity, the future appears promising. The limited take-away capacity on major export pipelines from Alberta will be mitigated when current projects are completed. While not all pipeline projects will proceed, increased capacity starting in late 1998 will benefit natural gas producing companies such as Petromet.

Another key aspect of our strategy is the emphasis on conducting operations in west central Alberta where our employees have developed considerable expertise. This region has provided advantages to Petromet, including the ability to acquire a large land position in core areas, develop extensive infrastructure, and the opportunity to conduct full cycle exploration and development.

Outlook Activity in the first quarter of 1998 remains high; however, we expect the oil and gas industry to experience a slowdown later in the year. Recent commodity price declines, particularly in oil, will result in lower revenues to the industry. Natural gas prices are anticipated to rise in late 1998 with continued growth in 1999. In light of these market conditions, Petromet contracted a significant portion of its anticipated gas production through the third quarter of 1998. While Petromet is largely uncontracted for the winter of 1998 and beyond, we will continue to monitor market conditions and contract accordingly.

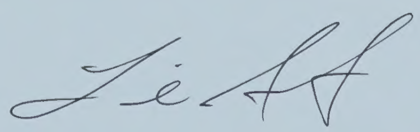
The Company's operations and investment opportunities are focused geographically where it has the expertise, high working interests, infrastructure, and operating control to pursue and exploit its emphasis on natural gas. Petromet's existing operations are highly efficient. The excellent reserve life of Petromet's assets provides a platform to support growth and to realize the potential upside of natural gas prices.

For 1998, an initial capital expenditure budget has been set at $40 million. Exploration and development efforts will remain focused in west central Alberta. We will build on our initial success in the new growth areas of Kakwa and High Prairie. Further drilling is planned for the Leduc reef targets at Wild River. Exploration and development will continue at Bigstone. Additional seismic surveying and follow-up drilling are anticipated by late 1998/early 1999 for one or more high risk/high reward Foothills gas prospects.

Production is expected to reach target growth levels in 1998 through further exploitation of core areas and the exploration of existing prospects. Petromet will work diligently to reduce finding and development costs in 1998.

Acknowledgements Let me express appreciation to those who contribute daily to the progress made by Petromet. We thank our shareholders for their ongoing support, our directors for their guidance, and all employees, both in the field and head office, for their many contributions. The depth of expertise and commitment of employees have enabled the Company to create, pursue and succeed in finding new opportunities for growth.

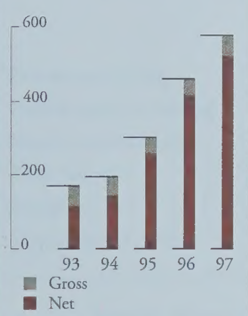
Petromet is well positioned to grow its business profitably in the current environment.



Laurie J. Smith
President and Chief Executive Officer
March 3, 1998


TURBO-JET
MAX 84 MPA

OPERATIONS REVIEW



UNDEVELOPED LAND HOLDINGS

THOUSANDS OF ACRES

Land Petromet utilizes a long-term approach to maintaining and growing its large undeveloped land base. High working interest lands are acquired in the early phase of exploration at reasonable cost. This approach provides Petromet with an excellent inventory of petroleum and natural gas rights for current and future exploration and development projects. In 1997 Petromet expanded its undeveloped land base by 26 percent to 519,699 net acres from 414,371 net acres in 1996.

Crown land sale acquisitions in 1997 totalled 118,320 net acres of petroleum and natural gas rights for a total net cost of $4.8 million, or an average bonus price of $40.31 per acre. Petromet's acquisition price compares favourably with the Alberta industry average cost of $81.11 per acre. While lower oil prices in 1998 may reduce land sale bids in oil prone areas, competition for gas acreage will remain high. The Company is well positioned with large acreage holdings in gas prone areas.

Land Holdings

	1997			1996		
(acres)	Gross	Net	WI%	Gross	Net	WI%
Developed	**60,963**	**42,429**	**70**	62,257	36,781	59
Undeveloped	**574,577**	**519,699**	**90**	457,483	414,371	91
Total	**635,540**	**562,128**	**88**	519,740	451,152	87

Drilling Petromet completed a record drilling program in 1997, participating in 31 gross (25 net) wells compared to 29 gross (21 net) wells in 1996. The 1997 program resulted in 14 gas wells, six oil wells and 11 dry holes, representing a 64 percent success rate. The average working interest was 80 percent, and 93 percent of the wells were Company-operated.

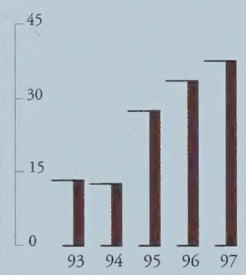
Approximately 50 percent of these wells were drilled in the Bigstone/Pass Creek/Tony Creek area. The remainder were split between Kakwa, High Prairie, Wild River and other locations west of the fifth and sixth meridians.

In 1998, Petromet will participate in approximately 30 wells at an average working interest of 75 percent.

Drilling Activity

	1997		1996	
	Gross	Net	Gross	Net
Natural gas	14	11	17	11
Oil	6	5	3	2
Dry	11	9	9	8
Total	31	25	29	21
Success rate		64%		62%
Average working interest		80%		73%

Production In 1997, Petromet's average natural gas production increased 12 percent to 37.2 million cubic feet per day from 33.1 million cubic feet per day in 1996. Average crude oil and natural gas liquids production increased to 971 barrels per day from 859 barrels per day in the previous year. On a million cubic feet equivalent basis, production averaged 46.9 in 1997 compared to 41.7 in 1996. Production gains were primarily due to continued activity at Bigstone, and recent drilling success at High Prairie and Kakwa.

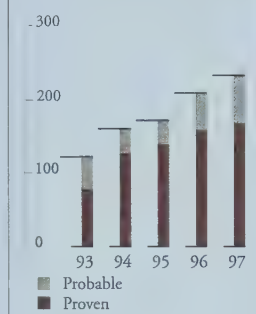


NATURAL GAS PRODUCTION
MMCF/D

Summary of Production

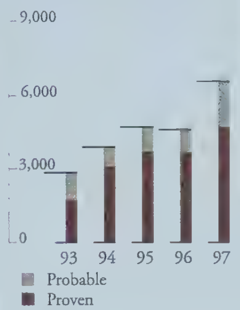
	1997			1996		
	Natural Gas mmcf/d	Oil & NGL bbls/d	Total mmcfe/d	Natural Gas mmcf/d	Oil & NGL bbls/d	Total mmcfe/d
Bigstone	28.7	865	37.4	26.3	796	34.3
Wild River	5.3	34	5.6	5.2	25	5.4
Other	3.2	72	3.9	1.6	38	2.0
Total	37.2	971	46.9	33.1	859	41.7

Reserves Petromet's reserves are independently evaluated at year end by Sproule Associates Limited (Sproule). At December 31, 1997, Petromet's natural gas reserves increased to 232.1 billion cubic feet from 207.2 billion cubic feet in 1996. This increase is due mainly to reserve additions through successful drilling at Kakwa, Wild River and Bigstone. Natural gas liquids reserves increased to 4.3 million barrels in 1997 from 4.2 million barrels in 1996. Crude oil reserves increased to 2.2 million barrels from 0.3 million barrels in the previous year due to light oil discoveries at High Prairie.



NATURAL GAS RESERVES

BCF



OIL & NGL RESERVES

MBBLS

During 1997, exploration and development added reserves of 52.8 billion cubic feet of gas and 2.8 million barrels of oil and natural gas liquids.

On a barrel of oil equivalent basis, increases in proven and probable reserves replaced production by a factor of 3.6 in 1997. The reserve life index is 12.5 years based on 1997 production and proven reserves at year end.

Reserve Summary

	Reserves		Discounted Value of Estimated Future Net Revenues ($millions)			
	Oil & NGL (mbbls)	Natural Gas (bcf)	0%	10%	15%	20%
Proven producing	3,622.5	108.2	266.2	132.5	108.4	92.4
Proven non-producing	121.3	4.1	6.9	3.4	2.7	2.3
Proven undeveloped	929.7	55.0	104.1	43.5	33.6	27.2
Total proven	4,673.5	167.3	377.2	179.4	144.7	121.9
Probable	1,853.3	64.8	77.3	20.1	13.7	9.8
December 31, 1997	6,526.8	232.1	454.5	199.5	158.4	131.7

Reserve volumes are before the deduction for royalty interests. Probable reserves values were reduced by 50 percent to allow for risk.

Price Forecasts The estimated future net revenues at December 31, 1997 are based upon the following price forecast utilized by Sproule in its report:

	Oil		Natural Gas	
	WTI at Cushing Oklahoma $US/bbl	Light Crude at Edmonton $Cdn/bbl	At Henry Hub Louisiana $US/mmbtu	TCGSL Average Field Price $Cdn/mmbtu
1998	20.52	27.23	2.19	1.79
1999	21.06	27.69	2.08	1.92
2000	21.61	28.43	2.12	2.02
2001	22.17	29.19	2.19	2.09
2002	22.75	29.97	2.26	2.18
	Escalation rate of 2.6% per year thereafter		*Escalation rate of 3.2% per year to 2010, 2% per year thereafter*	

Reserve Reconciliation

	Natural Gas (bcf) Proven	Probable	Total	Oil & NGL (mbbls) Proven	Probable	Total
December 31, 1996	157.4	49.8	207.2	3,649	910	4,559
Acquisitions	6.3	1.4	7.7	225	10	235
Exploration and development	33.2	19.6	52.8	1,666	1,102	2,768
Revisions of prior estimates	(4.5)	(3.7)	(8.2)	(211)	(122)	(333)
Dispositions	(11.5)	(2.3)	(13.8)	(301)	(47)	(348)
Production	(13.6)	–	(13.6)	(354)	–	(354)
December 31, 1997	167.3	64.8	232.1	4,674	1,853	6,527

Capital Expenditures Capital expenditures in 1997 concentrated on:

– increasing the land position in west central Alberta, a natural gas prone region;

– purchasing and shooting seismic in established and new exploration areas to identify and delineate new reservoir targets;

– expanding compression and gas gathering infrastructure at Bigstone to maintain low operating costs and increase production; and

– drilling exploratory wells to develop reserves in new areas.

The Company's operating philosophy in west central Alberta is to maintain operatorship and control of oil and gas operations. This is achieved through maintaining a high working interest and building new infrastructure to maintain low operating costs.

Capital Expenditures

($ millions)	1997	1996	1995
Exploration and development	$ 31.4	$ 17.5	$ 18.5
Facilities	14.4	3.1	13.1
Land	5.7	3.4	2.1
Acquisitions, net of dispositions	(1.9)	(0.8)	4.2
Total capital expenditures	$ 49.6	$ 23.2	$ 37.9

Finding and Development Costs Finding and development costs, for proven and half probable reserves, were higher in 1997 at $9.92 per barrel of oil equivalent compared to $5.52 per barrel of oil equivalent in 1996. Petromet's stage in the exploration cycle during 1997 warranted a higher level of land, seismic and facilities expenditures which impacted finding and development costs. Over the five-year period, from 1993 to 1997, these costs averaged $6.94 per barrel of oil equivalent.

The expansion into new growth areas in 1997 was accompanied by higher initial investments in land and seismic. A portion of the increased costs can also be attributed to the economics of drilling farm-in earning wells in new exploration areas. It is anticipated that in 1998, finding and development costs will more closely reflect the Company's historical average finding costs as ongoing exploration and development takes place on established areas and existing acreage in west central Alberta.

Finding and Development Costs

	1997	1996	1995	Three Year	Five Year
Capital expenditures ($ millions)	49.6	23.2	37.9	110.7	190.1
Proven reserves added (mmboe)	3.7	3.4	3.2	10.3	24.5
Average cost ($/BOE) (proven)	13.41	6.82	11.84	10.75	7.76
Proven and 50% probable reserves added (mmboe)	5.0	4.2	3.2	12.4	27.4
Average cost ($/BOE) (proven and 50% probable)	9.92	5.52	11.84	8.93	6.94

BIGSTONE

- Multi-zone potential, with liquids rich gas
- Producing zones include the Dunvegan, Gething, Viking, Notikewan, Cadomin and Triassic formations
- 40 producing gas wells in the area
- Low operating costs
- Operate a 54 percent owned modern gas processing facility

Property Description

Bigstone is Petromet's largest natural gas and natural gas liquids production centre. Substantial infrastructure in the area includes a 54 percent ownership in a modern gas processing facility which was expanded in 1997. In addition, 42 kilometres of pipeline infrastructure were completed for the Pass Creek and Tony Creek projects during the year. The Company's capital investment, combined with an aggressive exploration and development program, has resulted in strong historical growth and the opportunity for continued development and production enhancement.

1997 Activity

- Gas plant expanded to 85 mmcf/d and 2,600 bbls of NGL to accommodate increased third-party throughput
- Gas gathering system expanded to bring gas from Tony Creek
- Completed Pass Creek cross-over pipeline allowing for increased gas flows
- Rationalized assets by swapping non-operated gas for production to the Bigstone plant

1998 Activity

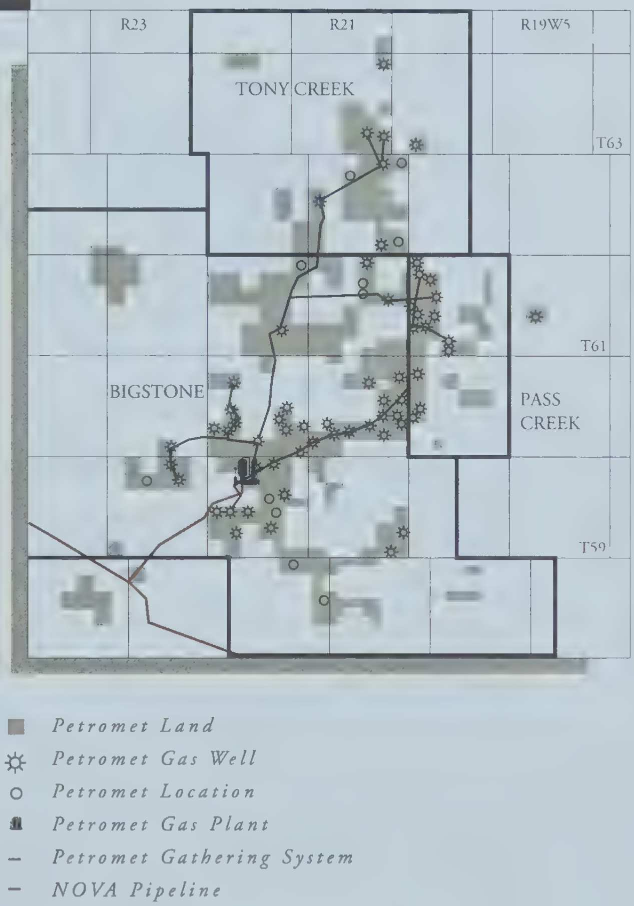
- Drill underbalanced horizontal wells to increase productivity from the Dunvegan gas pool
- Increase productivity from the Dunvegan oil pool
- Accelerate development of potential gas reserves in the south Bigstone area
- Drill six to eight wells

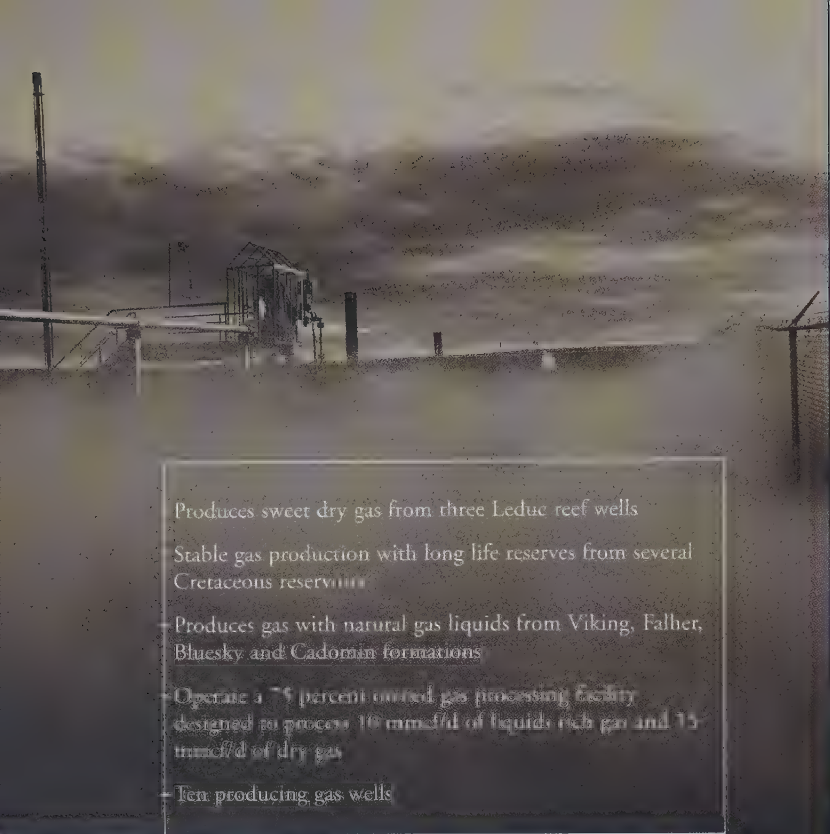
Undeveloped Land Holdings

- 90,560 gross acres
- 71,283 net acres

Average Net Production 1997

- 28.7 mmcf/d of natural gas
- 865 bbls/d of natural gas liquids





- Produces sweet dry gas from three Leduc reef wells
- Stable gas production with long life reserves from several Cretaceous reservoirs
- Produces gas with natural gas liquids from Viking, Falher, Bluesky and Cadomin formations
- Operate a 75 percent owned gas processing facility designed to process 10 mmcf/d of liquids rich gas and 15 mmcf/d of dry gas
- Ten producing gas wells

Property Description

WILD RIVER

At Wild River Petromet operates significant infrastructure including an extensive gas gathering system and a 75 percent working interest gas plant and dehydration facility. The Leduc reefs in this area are unique, producing sweet dry gas at a high reservoir pressure at depths of approximately 4,200 metres. Petromet plans to boost production in the area by the recompletion of existing wells which will include the use of horizontal drilling.

1997 Activity

- Completed a 35 square kilometre 3-D seismic survey to identify Leduc reef targets
- Drilled a 4,265 metre Leduc reef sweet gas well (79 percent working interest)
- Swapped into additional acreage
- Increased the Company's interest in the producing wells and gas plant by purchasing the interests of two industry partners

1998 Activity

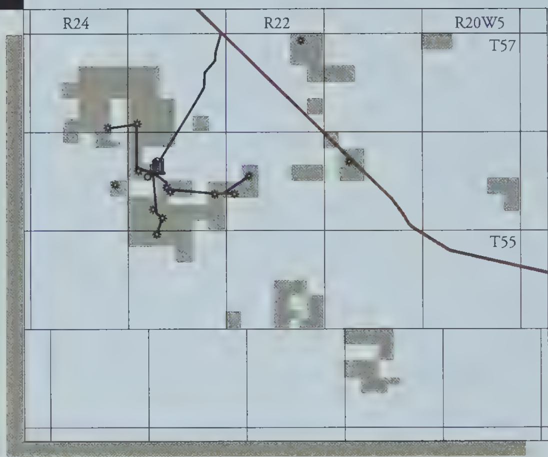
- Complete and tie-in the recently drilled Leduc reef gas well
- Shoot additional 3-D seismic in first quarter to identify further Leduc reef targets
- Drill at least one additional Leduc reef test
- Complete a horizontal gas well to evaluate production from a Cretaceous reservoir

Undeveloped Land Holdings

- 40,800 gross acres
- 33,873 net acres

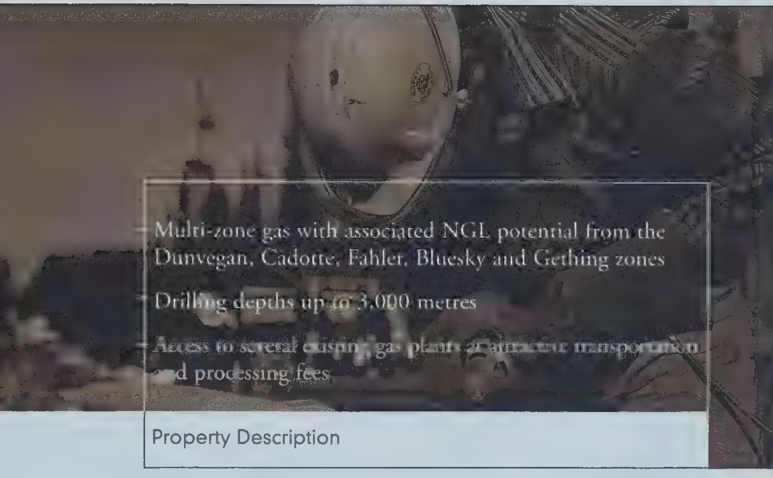
Average Net Production 1997

- 5.3 mmcf/d of natural gas
- 34 bbls/d of natural gas liquids



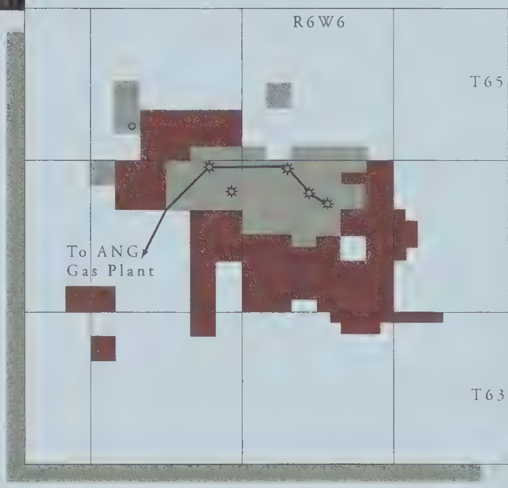
Petromet Land
Petromet Gas Well
Petromet Location
Petromet Gas Plant
Petromet Gathering System
NOVA Pipeline

KAKWA



- Multi-zone gas with associated NGL potential from the Dunvegan, Cadotte, Fahler, Bluesky and Gething zones
- Drilling depths up to 3,000 metres
- Access to several existing gas plants at attractive transportation and processing fees

Property Description



- *Petromet Land*
- *Petromet Option Land*
- ☼ *Petromet Gas Well*
- ○ *Petromet Location*
- — *Petromet Gathering System*

Kakwa represents a new growth area for Petromet. The Company initiated exploration by re-entering and completing a liquids rich gas well, which led to further successful drilling. Petromet's acreage under option may be earned by drilling further wells. The Company plans an active program at Kakwa during 1998 and beyond.

1997 Activity

- Drilled three wells and re-entered a fourth, resulting in four gas wells
- At year end, the re-entered well was producing two mmcf/d and 120 bbls/d of NGL
- Completed a nine-mile pipeline to tie-in wells to existing third-party gas processing facility
- Completed two large farm-ins as well as added to the undeveloped land base through Crown land purchases
- Completed several seismic programs

1998 Activity

- Three wells to be placed on production during the first quarter as third-party processing and transportation facilities are expanded
- Drill four to five wells
- Purchase and shoot additional seismic to refine drilling targets
- Evaluate deeper Devonian gas prospect on Petromet's land with drilling expected in the second half of 1998

Undeveloped Land Holdings

- 20,160 gross acres
- 15,960 net acres
- 29,920 acres under option

HIGH PRAIRIE

- Exploration focus area
- Light oil producing area from the Gilwood at a 2,300 metre depth

Property Description

The Company entered this new exploration area in 1997. Crown land purchases were augmented by earning, through drilling four wells, 12 sections of land. The area represents the first major light crude oil (38° API) focus area for the Company. Petromet owns a 99 percent interest and operates a 6,000 barrel per day battery and disposal facility. The Company has purchased additional working interests in several oil wells in the area.

1997 Activity

- Extensive use of 3-D seismic to identify drilling locations
- Drilled four wells in second half of the year, resulting in three oil wells
- Production commenced in late 1997

1998 Activity

- Shoot additional 3-D seismic in early 1998
- Drill four to six wells
- Additional production purchases in the first quarter
- Increase production through drilling and acquisitions

Undeveloped Land Holdings

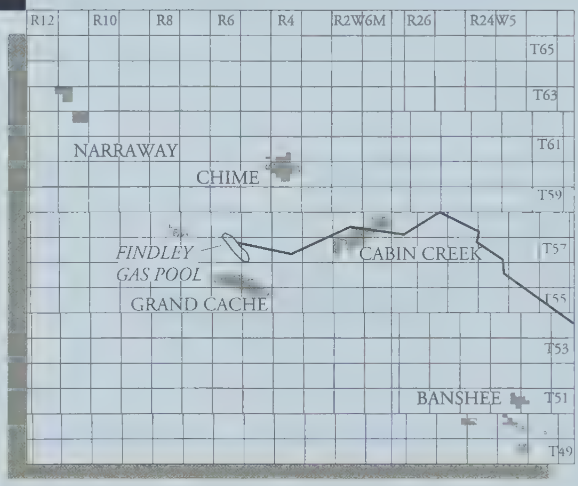
- 29,120 gross acres
- 27,528 net acres
- 19,040 acres under option

Petromet Land
Petromet Oil Battery
Petromet Oil Well
Petromet Location

WEST CENTRAL FOOTHILLS

Deep basin/foothills natural gas potential

Property Description



Petromet Land

ANG Central Foothills Gas Gathering System (to be completed December, 1998)

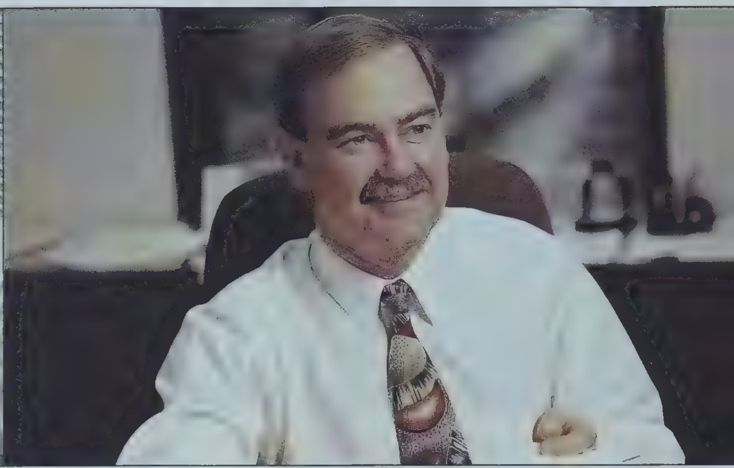
Petromet continues to acquire seismic and land in this area. Although the plans by Alberta Natural Gas to build a major natural gas gathering pipeline through our Cabin Creek acreage to the Findley gas field near the Company's Grand Cache exploration prospect were delayed, it now appears that the pipeline will be completed during the winter of 1998/1999. Petromet owns a 100-percent working interest in all the large acreage blocks shown on the West Central Foothills map.

The Company is accelerating its activity in the Grand Cache area where it owns a large contiguous block of land. Petromet's acreage is prospective for gas accumulations within large faulted structures. Drilling should commence in late 1998 once interpretation of seismic data is finalized. Other Petromet land tracts in this area will be re-evaluated for drilling during 1998. The West Central Foothills area has become very active for exploratory drilling to depths in excess of 5,000 metres. Land sale activity remains extremely high with very competitive prices.

Undeveloped Land Holdings

- 114,760 gross acres (100% owned)

MARKETING



Natural Gas Natural gas prices in 1997 continued to experience high volatility in response to developing issues and conditions within a dynamic market environment.

The increasing adaptability of the natural gas market to fundamental indicators demonstrates the efficiencies of an evolving market. Petromet's role as a producer is to anticipate and adapt accordingly, in order to add value while effectively managing market risks.

Colder than normal winter conditions at the onset of the 1996/1997 heating season resulted in strong gas prices in early 1997. NYMEX monthly natural gas contracts, the major indicator of the North American gas market, peaked in January 1997 at $4.254 US/mmbtu. Consistent with volatile commodity prices, above normal temperatures during the latter part of the winter signalled weak fundamentals which prevailed until late summer. At this time, the North American market has refocused on forecasted demand growth in the midwest and northeastern United States. This further fuelled new pipeline proposals for 1999 and beyond in addition to the approximately one billion cubic feet per day of expansions scheduled for completion in late 1998. Both the Northern Border and TransCanada Pipelines Limited projects appear to be on schedule for November 1998, with the Alliance and Viking Voyageur projects expected to be completed as early as the end of 1999. The anticipation of this additional export capacity has had a positive influence on pricing since August 1997, in part offset by the El Niño weather patterns that have caused warmer than normal temperatures for the 1997/1998 winter in the US and Canada.

In Alberta, high pipeline differentials relative to the overall North American average market will continue until Alberta is fully integrated, at which time differentials should narrow. With the new significant expansions in progress, this integration will largely take place by the end of 1998. Further significant expansions in 1999 will strengthen take-away capacities to handle the anticipated incremental supply. It remains to be seen if the Western Canadian producers can meet this challenge given the ever-increasing decline rates being experienced year over year. Over the short term, weather patterns, storage positions, summer pipeline maintenance and new supply timing will all contribute to uncertainties during this transitional stage.

Petromet's average natural gas price increased 13 percent to $1.85 per thousand cubic feet in 1997 compared to $1.63 per thousand cubic feet in 1996. The Company maintains a diverse market portfolio in order to manage risk effectively. Over 99 percent of its portfolio is sold to direct markets with less than one percent of the Company's gas sold to traditional supply aggregators. This strategy provides flexibility and control in all aspects of marketing, including the ability to take advantage of volatility, geographic diversity to major North American market centres, and pricing instruments to maximize netbacks. As well, key considerations in selecting buyers include: service, response time, and flexibility in converting pricing instruments.

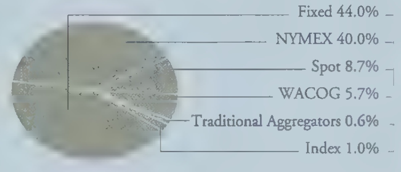
As part of its diversification, the Company experienced the first full year of direct exposure to the northeast US marketplace. In addition, the Company has participated in the Northern Border pipeline expansion through a marketing intermediary. Initial deliveries are scheduled for November 1998 to the US midwest. Both long-term markets have the benefit of achieving direct geographical market diversification while maintaining pricing term and instrument flexibility.

In terms of its market portfolio, Petromet remains focused on shorter-term pricing commitments in order to take advantage of favourable market conditions anticipated over the next few years.

Markets with pricing based upon NYMEX futures contracts increased to 40 percent of Petromet's portfolio in 1997 from 35 percent in 1996. Short-term fixed priced contracts accounted for approximately 44 percent of the Company's portfolio in 1997 while spot sales represented 8.7 percent. The remainder of the Company's portfolio was made up of Index pricing, WACOG pricing and traditional netbacks. Spot sales will continue to be a part of the Company's overall portfolio mix in order to accommodate production increases, maintain exposure to local markets, and provide additional volumes for new contracts at appropriate price levels.

In the future, the short term remains uncertain and the longer term appears very favourable for the Alberta natural gas producer.

Crude Oil and Natural Gas Liquids Pricing for Petromet's crude oil and natural gas liquids in 1997 decreased slightly to $23.42 per barrel versus $24.25 per barrel in 1996. Strong prices for all products, especially propane, contributed to this continued price strength.



1997 GAS SALES DISTRIBUTION

% OF VOLUME

Commencing in the third quarter of 1997, the majority of the Company's NGL production had the benefit of "higher-of" Edmonton postings or the major US market centres. In addition, the condensate market continues to be priced at a premium to crude oil due to the increased demand as a major diluent source for the heavier crude oil producers.

Crude oil markets have experienced a recent downturn, as evidenced by forward WTI prices and increasing heavy/light price differentials. Contributing factors included the commencement of Iraqi exports in 1997, increasing world oil supply both from OPEC and Non-OPEC producers, weak Far East economies that were evident in the third quarter of 1997, and a warm 1997/1998 winter season in both Europe and North America. It appears that current pricing may prevail for some time. Although the near-term global outlook may not be strong, Petromet, as a sweet light crude oil producer, is not subjected to the high differentials presently experienced by the heavy oil producers.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's Discussion and Analysis should be read in conjunction with the Consolidated Financial Statements contained in this annual report. The following discussion contains certain assumptions about future events and actual results may vary significantly from these assumptions.

Operations Operating income increased 20 percent in 1997 to $24.6 million from $20.5 million in 1996 mainly due to increased natural gas production and improved natural gas pricing.

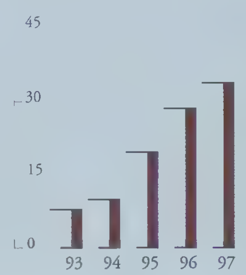
Operating Income

($ thousands)	1997	1996	1995
Petroleum and natural gas revenue	$ 33,927	$ 27,911	$ 19,144
Royalties, net of ARTC	5,802	4,258	2,423
Operating expenses	3,548	3,191	3,207
Operating income	$ 24,577	$ 20,462	$ 13,514

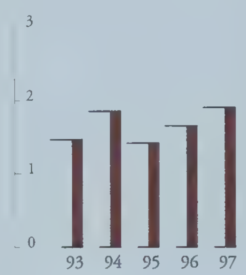
Petroleum and natural gas sales increased 22 percent to $33.9 million from $27.9 million in 1996. This increase resulted from gains in both production volumes and product pricing. Overall production increased 13 percent, contributing an additional $3.3 million to gross revenue, while product pricing increased eight percent, resulting in additional gross revenue of $2.7 million. Natural gas and NGL continue to account for the majority of Petromet's production as illustrated in the components of gross revenue:

Gross Revenue

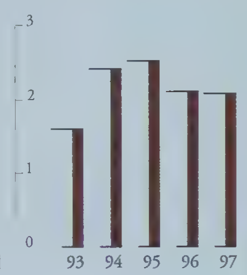
($ thousands)	1997 Gross Revenue	%	1996 Gross Revenue	%	1995 Gross Revenue	%
Natural gas sales	$ 25,135	74	$ 19,737	71	$ 13,919	73
NGL sales	7,480	22	7,392	26	4,758	25
Oil sales	822	3	230	1	462	2
Other	490	1	552	2	5	–
Petroleum and natural gas revenue	$ 33,927	100	$ 27,911	100	$ 19,144	100



GROSS REVENUE
$ MILLIONS



NATURAL GAS PRICES
$/MCF



OPERATING COSTS
$/BOE

Natural gas sales averaged 37.2 million cubic feet per day, up 12 percent from 33.1 million cubic feet per day in 1996. This higher sales volume increased natural gas revenue by $2.4 million. Production increases were attained mainly from Bigstone and new areas. Production from the new area of Kakwa commenced in mid December 1997 and, therefore, had a minimal effect on the current year. The impact of new production from both the Kakwa and Wild River areas is anticipated to add up to 10 million cubic feet per day in 1998. The average price received for natural gas, net of transportation costs, increased in 1997 to $1.85 per thousand cubic feet from $1.63 per thousand cubic feet in the prior year. This 13 percent increase in average price resulted in an additional $3.0 million in natural gas revenue.

Production of oil and NGL increased to 971 barrels per day from 859 barrels per day in 1996. The main production increase in natural gas liquids occurred from the Bigstone area, while increases in oil production were obtained from the High Prairie area which began producing in the last quarter of 1997. Increased production resulted in additional revenue of $1.0 million offset in part by a decrease in the average price received. The average price received in 1997 for liquids decreased three percent to $23.42 per barrel from $24.25 per barrel in the prior year. Other income arises mainly from the capital component charged to third parties processing through Company-owned facilities.

Royalty payments, net of ARTC, increased as a percentage of petroleum and natural gas sales to 17.1 percent in 1997 from 15.3 percent in 1996. In 1997 Alberta gas Crown royalties were reduced by approximately $800,000 as a result of final invoices received for the 1994, 1995 and 1996 production years. Current year royalties, without this adjustment, would have been 19.5 percent of gross revenue. This increase resulted from higher natural gas prices and, therefore, higher Crown royalty rates. ARTC receipts for the 1997 production year were $1.2 million versus $1.5 million in the 1996 production year. The net average royalty rate in 1998 is expected to increase slightly in accordance with the continuing impact of new production on which additional ARTC will not be applicable.

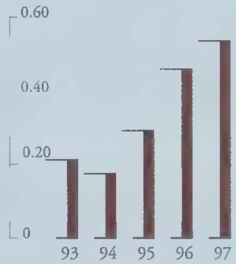
Operating costs on a BOE basis declined to $2.07 in 1997 from $2.09 in 1996 due to the sale of several non-operated properties and increased throughput at the Bigstone facility. Operating costs are presented net of the operating portion of recoveries realized from third-party processing in Company-owned facilities. Operating costs in 1998 are expected to increase due to higher costs associated with new oil production, as well as new gas production being processed through a third-party facility at Kakwa. Petromet continues to operate the majority of its production and will continue to pursue similar conditions whenever possible to maintain control over operating costs.

Cash Flow Cash flow from operations increased 30 percent to $20.6 million from $15.9 million in 1996. Cash flow on a BOE basis increased to $12.02 in 1997 from $10.44 in 1996.

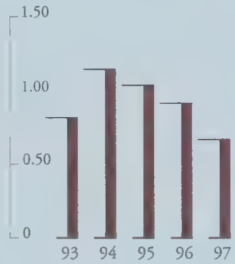
Cash Flow From Operations per BOE

	1997	1996	1995
Petroleum and natural gas revenue	$ 19.82	$ 18.30	$ 14.98
Royalties, net of ARTC	3.39	2.79	1.90
Operating costs	2.07	2.09	2.51
Operating netback	14.36	13.42	10.57
Interest	1.50	1.90	2.22
General and administrative	0.66	0.90	1.03
Current taxes	0.18	0.18	0.18
Cash flow from operations	$ 12.02	$ 10.44	$ 7.14
Per share	$ 0.53	$ 0.46	$ 0.29

General and administrative expenses were $1.1 million in 1997 (net of overhead recovered by the Company as operator), reflecting an 18 percent decrease over 1996. Gross expenses increased, reflecting higher activity levels and related staffing costs, but declined slightly on a BOE basis. Overhead recovered by the Company from operating, drilling and construction activities increased approximately $0.5 million in 1997 reflecting increased activity levels. Net general and administrative expenses were $0.66 per BOE in 1997 versus $0.90 per BOE in 1996. General and administrative expenses on a BOE basis are anticipated to moderately increase in 1998.



CASH FLOW PER SHARE
$



GENERAL & ADMINISTRATIVE
$/BOE

General and Administrative Expenses

($ thousands)	1997	1996	1995
Gross expenses	$ 2,646	$ 2,406	$ 2,298
Operator recoveries	1,519	1,033	977
Net expenses	$ 1,127	$ 1,373	$ 1,321
Average cost per BOE			
Gross expenses	$ 1.55	$ 1.58	$ 1.80
Operator recoveries	0.89	0.68	0.76
Net expenses	$ 0.66	$ 0.90	$ 1.04

Interest expense decreased to $2,854 in 1997 from $3,178 in 1996 due mainly to a lower average interest rate on banking facilities. Banking facilities are utilized primarily through bankers' acceptances resulting in a lower rate of interest than the bank's prime lending rate.

The convertible debentures bear interest at a fixed interest rate of 6.5 percent per annum on the issued value of $25 million. The convertible debentures were restated retroactively in 1996 to conform to the new recommendations of the Canadian Institute of Chartered Accountants relating to the presentation and disclosure of financial instruments. This restatement resulted in an equity component which is reflected in the financial statements as paid-in capital and is amortized as interest expense resulting in annual non-cash interest of $280,000.

Petromet's current tax is composed entirely of large corporations tax of $315,000 in 1997 versus $261,000 in 1996. This increase resulted from the Company's higher capitalization.

Net Income Depletion and depreciation on a BOE basis increased to $6.96 in 1997 from $6.23 in the prior year. The provision for future abandonment and site restoration, included in the depletion and depreciation, remained relatively consistent at $0.29 per BOE in 1997. Depletion on a per unit basis increased due to a higher depletable base resulting from current capital expenditures. Depreciation on gas plant facilities is calculated on a straight-line basis over the life of the facilities. The provision for future abandonment and site restoration is determined by management in consultation with the Company's engineers and is based on prevailing regulations, costs, technology and industry standards. The total future liability is estimated at $7.9 million at December 31, 1997 (1996 – $6.6 million). Current expenditures for abandonment and site restoration of producing properties were $54,000 (1996 – nil).

Depletion and Depreciation per BOE

	1997	1996	1995
Depletion	$ 6.06	$ 5.21	$ 4.95
Depreciation	0.61	0.71	0.67
Site restoration provision	0.29	0.31	0.32
	$ 6.96	$ 6.23	$ 5.94
Depletion rate	7.42%	7.28%	6.77%

The provision for deferred income taxes in 1997 is $4.0 million representing an effective rate of 45.7 percent versus a net effective rate of 37.2 percent in 1996. The effective tax rate for the prior year includes the tax effect of the gain on sale of investments in that year. The effective tax rate can vary substantially from year to year depending on the relative contribution of income sources, incentive allowances and non-deductible expenses. The Company had approximately $118 million of tax pools remaining at December 31, 1997 and will not be taxable on a current basis in 1998.

Net income from operations increased 22 percent to $4.4 million in 1997. Earnings per share from operations increased 10 percent reflecting an increase in weighted average common shares outstanding of 12 percent. Net income in 1996 and 1995 included a gain on sale of investments:

	1997		1996		1995	
	$ millions	$/share	$ millions	$/share	$ millions	$/share
Net income from operations	4.4	0.11	3.6	0.10	1.1	0.04
Gain on sale of investments, after tax	–	–	2.5	0.08	0.7	0.02
Net income	4.4	0.11	6.1	0.18	1.8	0.06

Liquidity and Capital Resources

Capitalization

($ thousands)	At cost Amount	%	At market Amount	%
Common share equity (closing share price on December 31, 1997 – $3.40)	$ 97,867	64	$ 145,253	73
Long-term debt, net of working capital	46,098	30	45,150	23
Deferred taxes	6,891	5	6,891	3
Other liabilities	1,661	1	1,661	1
Total	$ 152,517	100	$ 198,955	100

Capital expenditures in 1997 of $50 million were financed through the current year's cash flow of $20.6 million, the issuance of common shares and utilization of bank facilities. On September 29, 1997 the Company completed the issue of 2,716,049 flow-through common shares and 2,933,333 common shares for gross proceeds of $22 million. This issue brought the total outstanding common shares to 42,721,521 at year end. The Company has retroactively changed its accounting policy for flow-through shares to adjust for the estimated cost of the renounced tax deductions. Management believes this policy provides a measure of activities which is more comparable to similar sized companies. The effect of this change in policy is discussed further in the Notes to the Consolidated Financial Statements.

At year end the Company had a working capital deficiency of $3.0 million as a result of increased capital expenditures in the fourth quarter. Combined bank debt and working capital deficiency amounted to $22.8 million at year end. The current bank facilities are $40 million subject to the 1998 review of current activities and reserves. The 1998 capital budget is currently $40 million, although this amount is subject to revision as projects progress and additional opportunities arise.

Business Risks Exploration, development and production of oil and natural gas involve many risks which even a combination of experience, knowledge and careful evaluation may not be sufficient to overcome. These risks are mitigated by employing highly skilled staff, focusing exploration efforts in areas in which Petromet has existing knowledge and expertise or access to such expertise, using up-to-date technology methods and controlling costs to maximize returns. In addition, the Company's strategy of maintaining controlling interest in owning/operating facilities ensures that it will continue to be a low-cost producer. The Company has a comprehensive insurance program designed to mitigate risks and protect against significant loss; however, it is not fully insured against all of these risks, nor are all such risks insurable. Insurance for liability, property and business interruption is considered adequate and is consistent with common industry practice.

Financial risks include; exposure to fluctuation in interest rates, currency exchange rates and commodity prices. To reduce exposure to currency rate fluctuation associated with natural gas sales priced in US dollars, the Company has fixed the Canadian/US rate on a portion of 1998 production. At year end the cost to the Company to settle these contracts is estimated at $77,000. Although not currently utilized, the Company may institute hedging techniques for interest rates and commodity prices. If utilized, such transactions would be subject to certain limits on term and amount established by the Board of Directors. To mitigate commodity price risk, the Company maintains direct marketing control over its production and maintains a diversified portfolio to reduce exposure to short-term fluctuations. Purchasers of the Company's production are subject to internal credit review and the Company is not aware of any of its sales being subject to undue credit risk.

The oil and gas industry, while subject to stringent environmental regulatory control, is undergoing significant change with increased responsibility of self-regulation and compliance. In view of this situation, Petromet has taken a proactive approach in improving the environmental performance of the Company by the development of an Environmental Management System. This Environmental Management System essentially sets out the corporate environmental philosophy, objective, risk assessment, organizational structure, policies, procedures and auditing functions necessary in providing an effective comprehensive method of controlling all environmentally related issues. Such a system focuses on prevention and mitigation, rather than reaction and response techniques after environmental incidents have occurred. The system also incorporates existing safety policies and emergency response plans, as a complete package, to ensure the protection of the environment, the safety of the general public and all personnel. Petromet retains the services of an environmental consulting firm to provide advice and current regulatory information, to prepare environmental assessments for facilities, pipelines and sites prior to commencement of a project and to perform regular audits of operated facilities. The results of the regular audits are submitted to the Directors at each board meeting.

Year 2000 The Year 2000 problem arises because many information systems, upon which businesses depend, have been designed to identify years only by the last two digits. As a result, unless adequate preparations are made, the arrival of the year 2000 could cause systems failures or disruptions, with serious potential business consequences.

Petromet is currently assessing its exposure to the Year 2000 issue. This assessment involves all systems, including those that are part of operational activities, such as production and financial information systems. The assessment will also include addressing the potential effect that other organizations' systems may have on the Company.

The majority of the Company's systems are third-party software applications and, as such have, or will have, warranties with respect to Year 2000 compliance. Testing of the systems will occur during 1998 with field testing scheduled during plant turnarounds. Costs associated with this project are not expected to have a material effect on the financial results of the Company and will be expensed as incurred.

Cash Flow Sensitivities

	Cash Flow	
Approximate impact in 1998	$ millions	$/share
Natural gas		
Change of $0.10/mcf in average price	1.1	0.02
Change of 10 mmcf/d production	4.5	0.10
Oil & NGL		
Change of $1.00/bbl in average price	0.5	0.01
Change of 100 bbls/d production	0.5	0.01

SUPPLEMENTARY INFORMATION

Net Asset Value

($ millions, except per share)	Discounted at 10%	12%	15%
Present value of reserves, before income taxes, risked as to 50% for probable reserves*	$ 199.5	$ 180.6	$ 158.4
Value of undeveloped land*	29.7	29.7	29.7
Working capital (deficiency)	(3.0)	(3.0)	(3.0)
Long-term debt	(43.1)	(43.1)	(43.1)
Net asset value†	$ 183.1	$ 164.2	$ 142.0
Net asset value per share‡	$ 4.29	$ 3.84	$ 3.32

** Based on independent appraisal at December 31, 1997.*
† Does not include proprietary seismic and other assets.
‡ 42,721,521 shares outstanding at December 31, 1997.

Quarterly Summaries

	1997				1996			
	Mar. 31	June 30	Sep. 30	Dec. 31	Mar. 31	June 30	Sep. 30	Dec. 31
Financial ($ millions, except per share)								
Revenue	9.4	7.8	7.9	8.8	5.5	6.5	6.6	9.3
Cash flow	6.2	4.9	4.5	5.0	2.7	3.8	3.6	5.8
Cash flow per share	0.17	0.13	0.12	0.11	0.08	0.11	0.11	0.16
Net income	2.1	1.3	0.9	0.1	2.1	1.5	0.6	1.9
Net income per share	0.06	0.03	0.02	0.00	0.06	0.04	0.02	0.06
Capital expenditures	13.4	8.3	9.3	18.6	5.8	2.6	5.8	9.0
Operating								
Production								
Natural gas (mmcf/d)	38.3	37.3	36.3	36.8	28.7	33.9	32.3	37.4
Oil & NGL (bbls/d)	940	947	932	1,065	780	861	824	969
Average sales price								
Natural gas ($/mcf)	2.05	1.72	1.77	1.87	1.51	1.49	1.58	1.89
Oil & NGL ($/bbl)	26.53	21.59	21.27	24.23	21.26	21.47	23.23	29.95

MANAGEMENT'S REPORT

The accompanying consolidated financial statements and all information in the annual report are the responsibility of management. The consolidated financial statements have been prepared utilizing management's best estimates and judgements. In the opinion of management, these consolidated financial statements have been prepared within reasonable limits of materiality and are in accordance with Canadian generally accepted accounting principles.

Petromet maintains systems of internal controls to provide reasonable assurance that assets are safeguarded and to facilitate the preparation of relevant and reliable financial information on a timely basis.

External auditors, appointed by the shareholders, have examined the consolidated financial statements. The Audit Committee, consisting of a majority of non-management directors, has reviewed the consolidated financial statements with management and the external auditors. The Board of Directors has approved the consolidated financial statements on the recommendation of the Audit Committee.

L.J. Smith
President &
Chief Executive Officer

Shaun Supple

S.A. Supple
Chief Financial Officer

AUDITORS' REPORT

To the Shareholders of Petromet Resources Limited

We have audited the consolidated balance sheets of Petromet Resources Limited as at December 31, 1997 and 1996 and the consolidated statements of income, retained earnings and changes in financial position for each of the years in the three year period ended December 31, 1997. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 1997 and 1996, the results of its operations and the changes in its financial position for each of the years in the three year period ended December 31, 1997 in accordance with generally accepted accounting principles.

KPMG

Chartered Accountants
Calgary, Canada
March 6, 1998

CONSOLIDATED BALANCE SHEET

December 31 ($ thousands)	1997	1996
Assets		
Current		
Cash and term deposits	$ 204	$ 7
Accounts receivable	8,430	5,584
Inventory	1,912	1,330
Investments	125	125
	10,671	7,046
Property, plant and equipment (Note 3)	152,517	122,374
	$ 163,188	$ 129,420
Liabilities		
Current		
Accounts payable and accrued liabilities	$ 13,705	$ 6,105
Long-term bank debt (Note 4)	19,814	15,524
Convertible debentures (Note 5)	23,250	22,970
Future abandonment and site restoration costs	1,661	1,220
Deferred income taxes	6,891	3,488
Shareholders' Equity		
Share capital (Note 6)	78,980	65,623
Paid-in capital (Note 5)	2,800	2,800
Retained earnings	16,087	11,690
	97,867	80,113
	$ 163,188	$ 129,420

See accompanying notes.

On Behalf of the Board:

(Director)

(Director)

CONSOLIDATED STATEMENT OF INCOME

Year ended December 31 ($ thousands, except per share)	1997	1996	1995
Revenue			
Petroleum and natural gas	$ 33,927	$ 27,911	$ 19,144
Royalties, net of Alberta Royalty Tax Credit	(5,802)	(4,258)	(2,423)
	28,125	23,653	16,721
Expenses			
Operating	3,548	3,191	3,207
General and administrative	1,127	1,373	1,321
Depletion and depreciation	11,924	9,496	7,595
Interest on long-term debt	2,854	3,178	3,121
	19,453	17,238	15,244
Income before other item and taxes	8,672	6,415	1,477
Gain on sale of investments	–	3,738	961
Income before taxes	8,672	10,153	2,438
Taxes (Note 8)	4,275	4,035	641
Net income	$ 4,397	$ 6,118	$ 1,797
Earnings per share	$ 0.11	$ 0.18	$ 0.06
Weighted average number of common shares outstanding	38,522,103	34,347,166	31,611,591

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

Year ended December 31 ($ thousands)	1997	1996	1995
Balance, beginning of year (Notes 2,5)	$ 11,690	$ 5,572	$ 3,775
Net income	4,397	6,118	1,797
Balance, end of year	$ 16,087	$ 11,690	$ 5,572

See accompanying notes.

CONSOLIDATED STATEMENT OF CHANGES IN FINANCIAL POSITION

Year ended December 31 ($ thousands)	1997	1996	1995
Cash provided by (used in)			
Operating activities			
Net income	$ 4,397	$ 6,118	$ 1,797
Items not affecting cash:			
Depletion and depreciation	11,924	9,496	7,595
Deferred income taxes	3,960	3,774	415
Amortization of debt discount	280	280	280
Gain on sale of investments	–	(3,738)	(961)
Cash flow from operations	20,561	15,930	9,126
Change in non-cash working capital related to operations	570	(472)	(695)
	21,131	15,458	8,431
Investing activities			
Property, plant and equipment, net	(49,569)	(23,167)	(37,921)
Site restoration expenditures	(54)	–	–
Purchase of investments	–	(1,650)	–
Sale of investments	–	5,388	961
Change in non-cash working capital related to investments	3,583	1,112	(6,022)
	(46,040)	(18,317)	(42,982)
Financing activities			
Common shares, net of issuance costs	20,797	9,578	28,324
Long-term bank debt	4,290	(7,356)	6,738
Change in non-cash working capital related to financing	19	72	50
	25,106	2,294	35,112
Increase (decrease) in cash and term deposits	197	(565)	561
Cash and term deposits, beginning of year	7	572	11
Cash and term deposits, end of year	$ 204	$ 7	$ 572

See accompanying notes.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 1997 (in thousands of dollars)

1. Significant accounting policies

The consolidated financial statements of Petromet Resources Limited (the "Company") have been prepared by management in accordance with generally accepted accounting principles in Canada. The principal accounting policies followed by the Company are summarized below:

(a) Principles of consolidation

The consolidated financial statements include the accounts of the Company and its subsidiaries.

(b) Investments

Investments are recorded at the lower of cost and market value.

(c) Inventory

Inventory of equipment is stated at the lower of cost and net realizable value. Cost is determined using the specific item or average cost method.

(d) Property, plant and equipment

(i) Petroleum and natural gas properties The Company follows the full cost method of accounting for petroleum and natural gas operations whereby all costs of exploring for and developing petroleum and natural gas reserves are capitalized and accumulated in a single cost centre representing the Company's activity undertaken exclusively in Canada. Such costs include land acquisition costs, geological and geophysical expenses, lease rental costs on non-producing properties, costs of drilling both productive and non-productive wells, related plant and production equipment costs, and overhead charges directly related to these activities.

The provision for depletion and depreciation is determined on the unit-of-production method based on the estimated gross proven reserves as determined by independent engineers. Petroleum and natural gas reserves and production are converted into equivalent units based upon relative energy content. Costs associated with the acquisition and evaluation of significant unproved properties are excluded from amounts subject to depletion until such time as the properties are proved or become impaired. Gas plants and related facilities are depreciated using the straight line method based on the estimated useful life of the assets.

The capitalized costs less accumulated depletion and depreciation are limited to an amount equal to the estimated future net revenue from proven reserves (based on prices and costs at the balance sheet date) plus the unimpaired costs of non-producing properties less estimated future administrative expenses, development costs, financing costs, income taxes and estimated future abandonment and site restoration costs.

The amounts recorded for depletion and depreciation of property, plant and equipment and the provision for future abandonment and site restoration costs are based on estimates. The cost ceiling is based on such factors as estimated proved reserves, production rates, petroleum and natural gas prices and future costs. By their nature, these estimates are subject to measurement uncertainty and may impact the financial statements of future periods.

Proceeds from the sale of petroleum and natural gas properties are applied against capitalized costs, with no gain or loss recognized, unless such a sale would significantly alter the rate of depletion and depreciation.

(ii) Future abandonment and site restoration costs Estimated future abandonment and site restoration costs are provided for over the life of the proven reserves on a unit-of-production basis. Costs are estimated each year by management in consultation with the Company's engineers based on current regulations, costs, technology and industry standards. The annual charge is included in depletion and depreciation expense and actual abandonment and site restoration expenditures are charged to the accrued liability account as incurred.
(iii) Joint activities Substantially all of the exploration and production activities of the Company are conducted jointly with others and accordingly these consolidated financial statements reflect only the Company's proportionate interest in such activities.

(e) Financial instruments

The Company uses forward foreign exchange contracts to reduce its exposure to fluctuations in exchange rates on future domestic sales denominated in US dollars. Gains and losses incurred on forward contracts are recognized with the production revenue to which they relate.

(f) Flow-through shares

The Company has financed a portion of its petroleum and natural gas exploration activities with a flow-through share issue. The exploration and development expenditures funded by flow-through share expenditures are renounced to investors in accordance with tax legislation. Petroleum and natural gas properties and share capital are reduced by the estimated cost of the renounced tax deductions when the expenditures are incurred (Note 2).

(g) Earnings per share

Basic earnings per share has been calculated using the weighted average number of common shares outstanding during the year which includes shares reserved for issuance of special warrants. Fully diluted earnings per share is not materially different from basic earnings per share.

2. Change in accounting policy

During the year, the Company has retroactively changed its accounting policy for flow-through shares. Previously flow-through shares were recorded without adjustment for tax benefits renounced. Petroleum and natural gas properties and share capital are now reduced by the estimated cost of the renounced tax deductions. Management believes this policy provides a measure of activities which is more comparable with those of similar sized companies.

The impact of this change on the consolidated financial statements is as follows:

	1997	1996	1995
Net income	$ 764	$ 181	$ 73
Earnings per share	0.02	0 .01	–
Petroleum and natural gas properties	(9,532)	(2,299)	(1,008)
Share capital	(10,802)	(2,805)	(1,333)
Retained earnings	1,270	506	325

3. Property, plant and equipment

	1997	1996
Petroleum and natural gas properties, at cost	$ 189,836	$ 148,264
Accumulated depletion and depreciation	37,319	25,890
	$ 152,517	$ 122,374

Costs of unproved properties excluded from costs subject to depletion and depreciation at December 31, 1997 were approximately $13,068 (1996 – $9,350).

4. Long-term bank debt

The bank debt has been advanced under a revolving demand credit facility in the amount of $40,000. The debt bears interest at the bank's prime lending rate, US libor rate plus 3/4 percent or bankers' acceptance rates plus stamping fees. The facility is secured by a $100,000 floating charge oil and gas debenture but the agreement includes various covenants which influence the amount of additional debt and future security required under certain circumstances. The credit facility is renewable annually, however, no principal repayments are required providing certain reporting and financial covenants continue to be satisfied.

5 Convertible debentures

(a) The 6.5 percent convertible subordinate debentures were issued in 1994 in the principal amount of $25,000,000, are due March 31, 2004, with interest paid semi-annually. The debentures are convertible into common shares at $9.50 per share and are non redeemable until March 31, 1999, unless the closing price of the common shares for 30 consecutive trading days is $15.25 per share or more. After March 31, 1999, the debentures are redeemable in the event that the weighted average price at which the common shares are traded during a 30 consecutive trading day period is not less than 130 percent of the conversion price.

(b) In 1996, the Company retroactively adopted the new recommendations of the Canadian Institute of Chartered Accountants relating to the presentation and disclosure of financial instruments. Accordingly the convertible debentures were restated into their component parts as long-term liabilities and equity instruments, resulting in the restatement of certain previously reported information. Net income for the year ended December 31, 1995 decreased to $1,724 from $2,004 and retained earnings at December 31, 1994 decreased by $210.

6. Share capital

(a) The authorized share capital consists of an unlimited number of common shares and an unlimited number of preference shares, issuable in series. No preferred shares have been issued.

(b) Issued

	Shares	Amount
Balance, December 31, 1994	26,932,139	$ 28,270
Issued through public offering	7,000,000	29,750
Less: issue costs, net of deferred income tax of $632	–	(794)
Balance, December 31, 1995	33,932,139	$ 57,226
Issued for flow-through public offering	3,100,000	10,230
Less: issue costs, net of deferred income tax of $291	–	(361)
Less: effect of tax deductions renounced	–	(1,472)
Balance, December 31, 1996	37,032,139	$ 65,623
Issued for cash on exercise of stock options	40,000	50
Issued through public offering	2,933,333	11,000
Issued for flow-through public offering,	2,716,049	11,000
Less: issue costs, net of deferred income tax of $557	–	(696)
Less: effect of tax deductions renounced	–	(7,997)
Balance, December 31, 1997	42,721,521	$ 78,980

(c) Stock option plan

Stock options to acquire common shares are granted to directors, officers and other key employees from time to time at exercise prices equal to the market value of the shares at the date of the grant. At December 31, 1997, options to purchase 3,300,000 common shares were outstanding. These options are exercisable at prices ranging from $2.25 to $8.375 and expire on various dates between 1998 and 2002.

(d) Flow-through shares

During the year, the Company entered into flow-through share agreements whereby proceeds of $11,000 were received and the Company committed to expend and renounce $11,000 in qualified expenditures. Directors and officers of the Company subscribed for 80,000 flow-through shares, for consideration of $324.

7. Financial instruments

(a) Financial contracts

The Company entered into forward foreign exchange contracts in 1997 to sell US dollars for Canadian dollars. At December 31, 1997 the Company had outstanding contracts to sell $1,600 US dollars during 1998 at an average exchange rate of 1.3809 Canadian. The contracts are matched with anticipated future sales denominated in US dollars. At year end the cost to the Company to settle these contracts based on quoted forward foreign exchange rates was $77.

(b) Fair value of financial instruments other than financial contracts

The carrying amounts of cash and term deposits, accounts receivable, accounts payable and accrued liabilities and bank debt approximate their fair value. The fair value of other financial instruments is based on quoted market prices as follows:

	1997		1996	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Investments	$ 125	$ 260	$ 125	$ 245
Convertible debentures	23,250	22,437	22,970	21,750

8. Taxes

(a) The income tax expense differs from the amounts which would be obtained by applying the expected Canadian income tax rate as follows:

	1997	1996	1995
Income tax rate	44.6%	44.6%	44.6%
Computed "expected" tax provision	$ 3,868	$ 4,528	$ 1,087
Crown royalties	2,552	2,040	1,060
Non-deductible depletion	558	201	128
Resource allowance	(2,604)	(2,000)	(1,220)
Alberta Royalty Tax Credit	(542)	(655)	(657)
Non-taxable gains	–	(458)	(105)
Amortization of debt discount	125	125	125
Other	3	(7)	(3)
Large corporation tax	315	261	226
Provision for taxes	$ 4,275	$ 4,035	$ 641

(b) As at December 31, 1997 resource properties with a net book value of $15,800 (1996 – $6,900) have no cost base for income tax purposes. These differences arise primarily as a result of the acquisition of assets with a nominal value for income tax purposes and the issuance of flow-through common shares.

(c) As at December 31, 1997, the Company has available for deduction against future taxable income, resource deductions and undepreciated capital costs of approximately $118,000.

9. Differences in generally accepted accounting principles between Canada and the United States

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP") which, in most respects, conforms to accounting principles generally accepted in the United States ("US GAAP"). The significant differences in those principles are reflected in the following tables.

Adjustments to report the Company's income in accordance with US GAAP are as follows:

	1997	1996	1995
Net income	$ 4,397	$ 6,118	$ 1,797
Adjustments to increase (decrease) income	(947)	(377)	(269)
Depletion (a)	280	280	280
Amortization of debt discount (e)	447	115	623
Income taxes (b)	(220)	18	634
Net income – US GAAP	$ 4,177	$ 6,136	$ 2,431
Earnings per share – US GAAP	$ 0.11	$ 0.18	$ 0.08

Balance sheet items adjusted to be in accordance with US GAAP are as follows:

	1997		1996	
	Canadian GAAP	US GAAP	Canadian GAAP	US GAAP
Investments (d)	$ 125	$ 260	$ 125	$ 245
Property, plant and equipment (a,b)	152,517	163,439	122,374	126,246
Convertible debentures (e)	23,250	25,000	22,970	25,000
Deferred income taxes (b)	6,891	17,935	3,488	6,977
Share capital (c)	78,980	88,258	65,623	74,901
Paid in capital (e)	2,800	–	2,800	–
Unrealized gain on investments (d)	–	90	–	80
Retained earnings (a,b,c,d,e)	16,087	7,782	11,690	3,605

The following explanations discuss the significant differences between Canadian and US GAAP as they apply to the Company:

(a) Under US GAAP, the carrying value of petroleum and natural gas properties and related facilities, net of deferred income taxes, is limited to the present value of after tax future net revenue from proven reserves, discounted at 10 percent, (based on prices and costs at the balance sheet date) plus the lower of cost and fair value of unproven properties. The application of the full cost ceiling test under US GAAP did not result in a write down of capitalized costs.

(b) Under US GAAP, deferred income tax assets or liabilities are computed on the difference between financial statement and income tax bases of assets and liabilities. Deferred income tax provisions are based on the change during the period in the related deferred income tax asset or liability accounts.

(c) Under US GAAP, the reduction of stated capital, at December 31, 1992, would not have reduced the deficit. Accordingly, share capital as at December 31, 1997 would have been $88,258 (1996 – $74,901).

(d) Under US GAAP, the investments are classified as available for sale securities and would be reported at fair value, with the unrealized gains and losses net of related income taxes reported as a separate component of shareholders' equity.

(e) Under US GAAP, the equity component of the convertible debentures would be classified as debt on the balance sheet, in accordance with the legal form of the instrument and the amortization of the debt discount would not be reported as an expense in the income statement.

FIVE YEAR HISTORICAL SUMMARY

	1997	1996	1995	1994	1993
Financial ($ millions, except per share)					
Revenue					
Petroleum and natural gas	$ 33.9	$ 27.9	$ 19.1	$ 9.7	$ 7.4
Royalties	5.8	4.2	2.4	1.5	1.4
	28.1	23.7	16.7	8.2	6.0
Expenses					
Operating	3.5	3.2	3.2	1.3	0.8
General and administrative	1.1	1.4	1.3	0.6	0.4
Depletion and depreciation	11.9	9.5	7.6	3.1	2.3
Interest on long-term debt	2.9	3.2	3.1	1.8	–
	19.4	17.3	15.2	6.8	3.5
Income before other items and taxes	8.7	6.4	1.5	1.4	2.5
Other items	–	3.7	0.9	–	0.9
Income before taxes	8.7	10.1	2.4	1.4	3.4
Taxes					
Current	0.3	0.2	0.2	0.1	0.1
Deferred	4.0	3.8	0.4	0.4	0.6
	4.3	4.0	0.6	0.5	0.7
Net income	$ 4.4	$ 6.1	$ 1.8	$ 0.9	$ 2.7
Cash flow from operations	$ 20.6	$ 15.9	$ 9.1	$ 4.6	$ 4.7
Balance sheet information					
Capital expenditures, net	$ 49.6	$ 23.2	$ 37.9	$ 57.1	$ 22.3
Long-term debt	$ 43.1	$ 38.5	$ 45.6	$ 38.6	$ –
Working capital (deficiency)	$ (3.0)	$ 0.9	$ 4.6	$ (2.6)	$ 4.5
Shareholders' equity	$ 97.9	$ 80.1	$ 65.6	$ 34.8	$ 28.8
Common shares outstanding (millions)	42.7	37.0	33.9	26.9	23.8
Per share data					
Net income	$ 0.11	$ 0.18	$ 0.06	$ 0.03	$ 0.12
Cash flow from operations	$ 0.53	$ 0.46	$ 0.29	$ 0.17	$ 0.21
Operating					
Daily production					
Natural gas (mmcf)	37.2	33.1	27.0	12.5	13.0
Oil & NGL (bbls)	971	859	801	188	71
Proven Reserves					
Natural gas (bcf)	167.3	157.4	138.3	125.5	78.2
Oil & NGL (mbbls)	4,674	3,649	3,721	3,067	1,706
Proven plus probable reserves					
Natural gas (bcf)	232.1	207.2	171.1	159.5	119.6
Oil & NGL (bbls)	6,527	4,559	4,656	3,897	2,811
Wells drilled					
Gross	31	29	24	40	23
Net	25	21	18	24	15

CORPORATE INFORMATION

DIRECTORS

Edmond G. Eberts*†
President, RAPPORT Capital Formation Strategists Inc.
Toronto, Ontario

David H. Erickson
Senior Vice President
Calgary, Alberta

Charles J. Howard*
President, Ausnorarm Holdings Limited
Toronto, Ontario

P. Grenville Schoch†
Chairman of the Board
Toronto, Ontario

Laurie J. Smith*
President & CEO
Calgary, Alberta

Sharon A. Supple
Chief Financial Officer
Calgary, Alberta

** Member, Audit Committee*
† Member, Management Compensation Committee

OFFICERS

P. Grenville Schoch
Chairman of the Board

Laurie J. Smith
President & CEO

Johannes J. Nieuwenburg
Executive Vice President & COO

David H. Erickson
Senior Vice President

Sharon A. Supple
Chief Financial Officer

Blaine D. Holstein
Vice President, Operations

Christopher W. Nixon
Secretary

MANAGERS

John Duhault
Exploration Manager

Barbara Lee
Controller

Jeremy Newton
Land Manager

Greg Ruzicki
Drilling & Completions Manager

Mary-Lou Zimmer
Marketing Manager

REGISTERED OFFICE

BCE Place, Suite 1800 West
Box 754, 181 Bay Street
Toronto, Ontario M5J 2T9

EXECUTIVE OFFICE

Suite 350, 839 – 5 Avenue S.W.
Calgary, Alberta T2P 3C8
Telephone: (403) 269-2627
Fax: (403) 269-3922

SOLICITORS

Osler, Hoskin & Harcourt
Calgary and Toronto

Burstall Ward
Calgary

BANKER

Royal Bank of Canada
Calgary

TRANSFER AGENT AND REGISTRAR

CIBC Mellon Trust Company
Calgary and Toronto

AUDITORS

KPMG
Calgary

LISTED

The Toronto Stock Exchange
Common share symbol: PNT
Convertible debenture symbol: PNT.DB

National Association of Securities Dealers, Inc. (NASDAQ)
Common share symbol: PNTGF

ANNUAL INFORMATION FORM

Copies of the Company's Annual Information Form are available upon request.

NOTICE OF ANNUAL GENERAL MEETING

The Annual General Meeting of shareholders will be held on May 13, 1998 at 3:00 pm at the Westin Hotel, 320 – 4th Ave. S.W., Calgary, Alberta. All shareholders and other interested parties are invited to attend.

ABBREVIATIONS

ARTC	Alberta Royalty Tax Credit
bbls	barrels
bcf	billions of cubic feet
bcfe	billions of cubic feet equivalent
BOE	barrels of oil equivalent (10 mcf = 1 bbl)
mbbls	thousands of barrels
mboe	thousands of barrels of oil equivalent
mcf	thousands of cubic feet
mcfe	thousands of cubic feet equivalent (1 bbl = 10 mcf)
mmbbls	millions of barrels
mmboe	millions of barrels of oil equivalent
mmcf	millions of cubic feet
mmcfe	millions of cubic feet equivalent
NGL	natural gas liquids

This report is printed on recycled paper containing a minimum of 20% post-consumer fibre.